State of California

Department of Water Resources

Proposed

Determination of Revenue Requirements

For the Period

January 1, 2004, Through December 31, 2004

To Be Submitted To
The California Public Utilities Commission
Pursuant To
Sections 80110 and 80134 of the California Water Code

July 17, 2003

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A. The Proposed Determination

General

Pursuant to Sections 80110 and 80134 of the California Water Code and the Rate Agreement between the State of California Department of Water Resources (the "Department") and the California Public Utilities Commission (the "Commission") dated March 8, 2002 (the "Rate Agreement"), the Department plans, by means of this Proposed Determination of Revenue Requirements (this "2004 Proposed Determination"), to advise and notify the Commission of its revenue requirement for the period January 1, 2004, through and including December 31, 2004 (the "2004 Revenue Requirement Period"). The Department has made these revenue requirement and "just and reasonable" determinations in accordance with the Rate Agreement, California Water Code, Division 27 (the "Act"), and California Code of Regulations, Division 23, Chapter 4, Sections 510–517 (the "Regulations"). Capitalized terms used and not otherwise defined herein have the meanings given to such terms in the Rate Agreement or the Indenture under which the Department's Power Supply Revenue Bonds were issued (the "Bond Indenture").

The Department assumed responsibility for the purchase of the net short energy requirements of the retail customers of the three California investor-owned utilities (the "Utilities" or "IOUs") namely, Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE") and San Diego Gas & Electric Company ("SDG&E") in January and February of 2001. On February 1, 2001, Assembly Bill 1 from the First Extraordinary Session of 2001 was enacted into law, containing, among other things, the Act. The Act authorized the Department to purchase the net short energy requirements of the customers. The "net short" is equal to total IOU customer energy requirements minus supply from resources owned, operated or contracted by the IOUs. The Department, in accordance with the Act, procured the net short requirements of the IOUs using a combination of long-term power contracts and short-term energy purchases through the end of 2002. After allowing for the energy provided under the Department's long-term power contracts, the amount of energy required to be purchased (initially on a short-term basis) to meet IOU customer needs, has been designated the "residual net short". On January 1, 2003, the IOUs resumed the responsibility of procuring the residual net short. Since that time, the Department's role in procuring power to meet the net short has been limited to the provision of power from long-term power contracts entered into by the Department prior to January 1, 2003.

The costs of the Department's purchases to meet the net short requirements of the customers of the IOUs, including the costs of administering the long-term contracts, are to be recovered from payments made by the customers and collected by the IOUs on behalf of the Department. The terms and conditions for the recovery of the Department's costs from customers are set forth in the Act, the Regulations, the Rate Agreement and orders of the Commission. Among other things, the Rate Agreement established the foundation for a "Bond Charge" (as that term is defined in the Rate Agreement) that is designed to recover the Department's costs associated with its bond financing activity ("Bond Related Costs") and a "Power Charge" (as that term is defined in the Rate Agreement) that is designed to recover "Department Costs", or the Department's "Retail Revenue Requirements" (as those terms are defined in the Rate Agreement), including power supply-related costs. Subject to the conditions described in the Rate Agreement and other Commission Decisions, Bond Charges and certain charges designed to recover Department Costs may also be imposed on the customers of Electric Service Providers (as that term is defined in the Rate Agreement).[1]

The Department funded its purchases of energy from January 17, 2001, through December 31, 2002, from three sources: payments collected from retail customers by the IOUs on behalf of the Department, advances from the State General Fund, and the proceeds of an interim financing of $4.3 billion issued in June 2001 (the "Interim Loan"). In October and November of 2002, the State issued $11.263 billion of revenue bonds. The proceeds were applied to reimbursing the General Fund and payment of the Interim Loan, and certain debt service reserves and operating reserves were created. Repayment of the bonds will be made from the Bond Charge established in the Rate Agreement and from amounts in the related accounts, as described in more detail herein.

Pursuant to Sections 80110 and 80134 of the California Water Code and the Rate Agreement, this Determination contains information on the amounts required to be recovered, on a cash basis, in the 2004 Revenue Requirement Period.

A reconciliation of the Department's costs and revenues relative to revenue requirements through 2003 will be provided separately when actual data is available. Due to the time required for the California Independent System Operator ("CAISO" or "ISO") settlement process to be finalized, the information supporting the reconciliation of 2003 costs is expected to be available in or around May of 2004, and the "true-up" with respect to Department revenue requirements (as opposed to any true-up of the allocation of those requirements) will occur as new revenue requirements are determined. For example, this 2004 Proposed Determination takes into account preliminary actual results of Department operations through March 31, 2003 and revised projections of results of operations through the end of 2003.

For the 2004 Revenue Requirement Period, this determination contains information on the following[2]: (a) the projected beginning balance of funds on deposit in the Electric Power Fund (the "Fund"), including the amounts projected to be on deposit in each account and sub-account of the Fund; (b) the amounts projected to be necessary to pay the principal, premium, if any, and interest on all bonds as well as all other Bond Related Costs as and when the same are projected to become due, and the projected amount of Bond Charges

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1 Under the Rate Agreement, "Department Costs" are all costs of the program other than "Bond Related Costs" and the "Retail Revenue Requirement" is the amount to be recovered from "Power Charges" on IOU customers (i.e., net of amounts recovered from Electric Service Provider customers for Department Costs). As a result, the assessment on customers of Electric Service Providers of charges to recover Department Costs ("Direct Access Power Charge Revenues") reduces the amount of the "Retail Revenue Requirement", but has no material impact on the amount of Department Costs. In the absence of final action to determine the amount Direct Access Power Charge Revenues, this 2004 Proposed Determination will generally treat the amount of the Retail Revenue Requirement as being the same as the amount of the Department Costs to be recovered from Power Charges on IOU customers, unless a distinction is necessary.

2 Where appropriate, the Department has provided information in this determination on a quarterly basis for the revenue requirement period. In other instances, particularly where information might be considered market-sensitive, the Department has provided information on an annual basis.

required to be collected for such purpose; and (c) the amount needed to meet the Department Costs, including all Retail Revenue Requirements.

Determination of Revenue Requirements

Pursuant to the Act, the Rate Agreement and the Regulations, the Department hereby determines, on the basis of the materials presented and referred to by this Determination (including the materials referred to in Section I), that its cash basis revenue requirement for the 2004 Revenue Requirement Period is $5.472 billion, consisting of $4.652 billion in Department Costs and $0.820 billion in Bond Related Costs.

Table A-1 shows a summary of the Department's revenue requirements and accounts associated with its projected Department Costs ("Power Charge Accounts") for the 2004 Revenue Requirement Period. A similar summary of the Department's revenue requirements and accounts associated with its Bond Related Costs ("Bond Charge Accounts") is presented in Table A-2. Definitions of key accounts and subaccounts are presented within each table.

TABLE A-1
SUMMARY OF THE DEPARTMENT'S 2004 REVENUE REQUIREMENTS AND ACCOUNTS POWER CHARGE ACCOUNTS[1]

Line	Description	2004[2]	2003[3]	Difference
1	*Beginning Balance in Power Charge Accounts*			
2	Operating Account	748	1,273	(525)
3	Priority Contract Amount	-	-	-
4	Operating Reserve Account	630	777	(148)
5	**Total Beginning Balance in Power Charge Accounts**	**1,378**	**2,050**	**(672)**
6	*Power Charge Accounts Operating Revenues*			
7	Power Charge Revenues from Bundled Customers	4,652	3,288	1,364
8	Power Charge Revenues from Direct Access Customers	-	14	(14)
9	Extraordinary Receipts from Utilities	-	539	(539)
10	Other Power Sales	134	132	2
11	Interest Earnings on Fund Balances	31	32	(1)
12	**Total Power Charge Accounts Operating Revenues**	**4,816**	**4,005**	**811**
13	*Power Charge Accounts Operating Expenses*			
14	Administrative and General Expenses	59	49	10
15	Total Power Costs	4,794	4,628	166
16	Ancillary Services	-	22	(22)
17	Extraordinary Costs	71	-	71
18	**Total Power Charge Accounts Operating Expenses**	**4,924**	**4,698**	**226**
19	Net Operating Revenues	(108)	(693)	585
20	Net Transfers from/(to) Bond Charge Accounts	-	-	-
21	Total Net Revenues	(108)	(693)	585
22	**Ending Aggregate Balance in Power Charge Accounts**	**1,270**	**1,357**	**(87)**

2004 Target Minimum Power Charge Account Balances	**Target (Millions of Dollars)**		**Difference**
Operating Account: This minimum balance is targeted to cover intra-month volatility as measured by the maximum difference in revenues and expenses in a calendar month under a stress scenario.	286	348	(62)
Operating Reserve Account: Used to cover deficiencies in the Operating Account. It is sized as the maximum seven-month difference between operating revenues and expenses as calculated under a stress scenario.	591	630	(39)
Total Operating Reserves:	877	978	(101)

[1] Numbers may not add due to rounding.

[2] As proposed herein.

[3] As reflected in the Department's 2003 Supplemental Determination.

TABLE A-2
SUMMARY OF THE DEPARTMENT'S 2004 REVENUE REQUIREMENTS AND ACCOUNTS: BOND CHARGE ACCOUNTS

Line	Description	Proposed 2004 Filing
		($ Millions)
1	*Beginning Balance in Bond Charge Accounts*	
2	Bond Charge Collection Account	236
3	Bond Charge Payment Account	447
4	Debt Service Reserve Account	927
5	**Total Beginning Balance in Bond Charge Accounts**	**1,610**
6	*Bond Charge Accounts Revenues*	
7	Bond Charge Revenues from Utiltities	820
8	Revenue Bonds Net Proceeds	-
9	Interest Earnings on Fund Balances	32
10	**Total Bond Charge Accounts Revenues**	**852**
11	*Bond Charge Accounts Expenses*	
12	Debt Service on Bonds	725
13	Other Bond Charge Account Expenses	-
14	**Total Bond Charge Accounts Expenses**	**725**
15	Net Bond Charge Revenues	126
16	Net Transfers from/(to) Power Charge Accounts	-
17	Total Net Revenues	126
18	**Ending Aggregate Balance in Bond Charge Accounts**	**1,737**

2003 Target Minimum Bond Charge Account Balances	**Target ($ Millions)**
Bond Charge Collection Account: An amount equal to one month's required deposit to the Bond Charge Payment Account for projected debt service	75 - 78
Bond Charge Payment Account: An amount equal to the debt service accrued and unpaid through the end of the third next succeeding calendar month	319 - 721
Debt Service Reserve Account: An amount equal to maximum annual debt service	927

Future Adjustment of Revenue Requirements

The Department reserves the discretion to revise its revenue requirements for the 2004 Revenue Requirement Period in recognition of the potential for significant or material changes in the California energy market, status of market participants, the Department's associated obligations and operations, or any other events that may materially affect the realized or projected financial performance of the Power Charge Accounts or the Bond Charge Accounts. In such event, the Department will inform the Commission of such material changes and will revise its revenue requirement projections accordingly.

Several relevant factors are discussed in more detail within Section E.

B. Background

The Act. Section 80110 of the Water Code provides in part that "The Department shall be entitled to recover, as a revenue requirement, amounts and at the times necessary to enable it to comply with Section 80134, and shall advise the Commission as the Department determines to be appropriate." Section 80110 also provides that "any just and reasonable" review of its revenue requirements shall be conducted and determined by the Department. In addition, Section 80134 of the Water Code provides that:

> "(a) The Department shall, and in any obligation entered into pursuant to this division may covenant to, at least annually, and more frequently as required, establish and revise revenue requirements sufficient, together with any moneys on deposit in the fund, to provide all of the following:
>
> "(1) The amounts necessary to pay the principal of and premium, if any, and interest on all bonds as and when the same shall become due.
>
> "(2) The amounts necessary to pay for power purchased by it and to deliver it to purchasers, including the cost of electric power and transmission, scheduling, and other related expenses incurred by the department, or to make payments under any other contracts, agreements, or obligation entered into by it pursuant hereto, in the amounts and at the times the same shall become due.
>
> "(3) Reserves in such amount as may be determined by the Department from time to time to be necessary or desirable.
>
> "(4) The pooled money investment rate on funds advanced for electric power purchases prior to the receipt of payment for those purchases by the purchasing entity.
>
> "(5) Repayment to the General Fund of appropriations made to the fund pursuant hereto or hereafter for purposes of this division, appropriations made to the Department of Water Resources Electric Power Fund, and General Fund moneys expended by the department pursuant to the Governor's Emergency Proclamation dated January 17, 2001.
>
> "(6) The administrative costs of the Department incurred in administering this division.
>
> "(b) The Department shall notify the Commission of its revenue requirement pursuant to Section 80110."

The Rate Agreement. In February, 2001, the Commission issued a decision adopting the Rate Agreement between the Commission and the Department establishing the procedures to be followed to calculate and adjust the charges to customers for Department power, such that the Department is assured of recovering its Retail Revenue Requirements.[3] The purpose of the Rate Agreement was to facilitate the issuance of bonds that enabled the repayment of the General Fund and Interim Loan, and the funding of appropriate reserves for the bonds. On November 14, 2002, the final bond issue was completed. The General Fund and Interim Loan were repaid.

The Rate Agreement establishes two streams of revenue for the Department. One revenue stream is generated from "Bond Charges" imposed for the purpose of providing sufficient funds to pay "Bond Related Costs." Bond Charges are applied based on the aggregate amount of electric power sold to each customer by the Department and the applicable IOU, and, to the extent provided by final unappealable Commission orders, Electric Service Providers. Bond Related Costs include Bond debt service (including related Qualified Swap payments), credit enhancement and liquidity facilities charges, and costs relating to other financial instruments and servicing arrangements relative to the Bonds. Bond Charges are imposed upon customers within IOU service territories regardless of whether those customers purchase their energy supplies from the Department and/or IOUs or Electric Energy Providers. The Rate Agreement requires the Commission to impose Bond Charges that are sufficient, together with amounts on deposit in the Bond Charge Collection Account, to pay all Bond Related Costs, as well as meet all Bond covenants as they come due.

The second revenue stream is generated from "Power Charges" imposed on customers who buy power from the Department, and is designed to pay for "Department Costs," including the costs that the Department incurs to procure and deliver power. The Rate Agreement requires the Commission to impose Power Charges that are sufficient to provide moneys in the amounts and at the times necessary to satisfy the Retail Revenue Requirements specified by the Department.

Revenues received from Power Charges and Bond Charges, as well as the payment of expenditures and obligations from such revenues, are held in, and accounted for under, the Electric Power Fund established by the Department under the Act.

Revenues from Power Charges are deposited into an "Operating Account." Funds in the Operating Account are used to pay Department Costs and are also transferred on a priority basis to a "Priority Contract Account." The Priority Contract Account is used to pay for the costs that the Department incurs under its Priority Long Term Power Contracts ("PLTPCs") which have terms that require the Department to pay for power purchased under these contracts ahead of Bond Related Costs (such as Bond debt service).

In addition, the Department funds an "Operating Reserve Account" to be drawn upon in the event that there are shortfalls in the Operating Account or the Priority Contract Account.

Revenues from Bond Charges are deposited into a "Bond Charge Collection Account". Funds in the Bond Charge Collection Account are transferred periodically to a "Bond Charge Payment Account". Funds in the Bond Charge Payment Account may only be used

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[3] California Public Utilities Commission, Decision 02-02-051, "Opinion adopting a Rate Agreement between the Commission and the California Department of Water Resources," adopted February 21, 2002, as modified by Decision 02-03-063, adopted March 21, 2002.

to pay Bond Related Costs. Funds in the Bond Charge Collection Account may be used to pay amounts due under the PLTPCs to fulfill the priority payment requirements of the PLTPCs if and only if amounts in the Priority Contract Account, the Operating Account and the Operating Reserve Account are insufficient. If the Bond Charge Collection Account is used to pay amounts due under PLTPCs, the Bond Charge Collection Account is to be replenished or reimbursed from amounts when available in the Operating Account.

These Bond Charge and Power Charge accounts are further described in Section D.

The Department is making this proposed determination of revenue requirements consistent with the requirements of Sections 80110 and 80134 of the California Water Code and is providing information consistent with the requirements of the Rate Agreement. Upon completion of the administrative process, the Department will determine its just and reasonable revenue requirements for the 2004 period.

Prior Proceedings Relating to 2003 and the Projected Starting Balance for 2004. On August 16, 2002 the Department published its Determination of Revenue Requirement for 2003 (the "August 16, 2002 Determination"), and filed that Determination with the Commission on August 19, 2002. On December 17, 2002, the Commission rendered Decision 02-12-045 "Opinion Adopting Interim Allocation Of the 2003 Revenue Requirement of The California Department of Water Resources." Decision 02-12-052 (Order Correcting Error) was also issued on December 17, 2002, correcting various tables and numbers contained in Decision 02-12-045. Decision 02-12-045 excluded $29 million identified in relation to a power contract agreement between the Department and the California Consumer Power and Conservation Financing Authority ("CPA"). On February 13, 2003, the Commission issued Decision 03-02-031 amending Decision 02-12-045, as corrected by Decision 02-12-052, to allocate the aforementioned $29 million. The Commission, in Decision 02-12-045, provided an interim allocation of the Revenue Requirement, and as part of the decision, requested the Department submit a Supplemental Determination to include information availability after the submittal.

On July 1, 2003, the Department issued its Supplemental Determination of Revenue Requirements for the period of January 1, 2003 through December 31, 2003 (the "2003 Supplemental Determination"). The Department determined, on the basis of the materials presented and referred to by the 2003 Supplemental Determination, its Retail Revenue Requirement for the period of January 1, 2003 through December 31, 2003, to be $3.288 billion, after taking into account the application of Operating Account surplus funds described below and the amounts that had been generated from charges on the customers of Electric Service Providers.

The transition of responsibility for the procurement of the residual net short from the Department to the IOUs and a reexamination of possible future outcomes under stress scenarios permitted the Department to reduce the Minimum Operating Expense Available Balance ("MOEAB") from $1 billion to $348 million, and to reduce its Operating Reserve Account Requirement ("ORAR") from $777 million to $630 million. The $777 million ORAR was based on 18 percent of total 2003 operating expenses as required by the Bond Indenture. The $630 million target balance was calculated based on the maximum seven-month difference in operating expenses and revenues under a stress scenario, also consistent with Bond Indenture requirements. In addition, the reexamination of the Stress Case isolated the cash flow outcome resulting solely from the stress case as compared to the base case outcome. The total reduction in fund balance requirements was $799 million from the fund balance requirements identified in the August 16, 2002 Determination.

The Department's revenues from retail customers projected in the August 2002 filing (assuming the same charges as implemented by the Commission in Decision 03-02-031) decreased by $1.360 billion due to load and contract dispatch changes and the Department's ability to decrease account balance requirements, both described in Section E of the 2003 Supplemental Revenue Requirement.

Finally, the Department projects that it will receive from PG&E all applicable DWR charges for energy delivered to the PG&E customers. The amount of such charges relating to the period January 17, 2001 through the end of March, 2003, that had not been remitted as of March 31, 2003, was estimated to be at least $539 million.

Taking into account the factors summarized in the preceding paragraphs, and conditioned upon the receipt from PG&E of at least the $539 million described above, the amount in the Operating Account on July 1, 2003, in excess of the amount required (if DWR charges were not modified) was projected to be $1.002 billion. As a result, conditioned upon receipt of such $539 million and assuming that DWR charges are not modified prior to July 1, 2003, the Department determined that its Retail Revenue Requirement for the period July 1, 2003 through and including December 31, 2003, net of the application of that $1.002 billion is $2.041 billion on a cash basis and that such requirement may be implemented in a manner that assumes that $1.002 billion is available to pay Department Costs immediately as of July 1, 2003 (i.e., need not be reserved).

This 2004 Proposed Determination assumes that the Commission will take action consistent with the 2003 Supplemental Determination, resulting in a starting balance for the 2004 Revenue Requirement Period as projected herein.

The Department is making this proposed determination of revenue requirements consistent with the requirements of Sections 80110 and 80134 of the California Water Code and is providing information consistent with the requirements of the Rate Agreement. Upon completion of the procedures set forth in the Regulations, the Department will determine its just and reasonable revenue requirements for the 2004 Revenue Requirement Period.

C. The Department's Proposed Determination of Revenue Requirements for The Period of January 1, 2004 Through December 31, 2004

Retail Revenue Requirement Determination

For the 2004 Revenue Requirement Period, the Department's revenue requirements consist of Department Costs and Power Charge revenues, and Bond Related Costs and Bond Charge Revenues.

Department Costs include:

(1) Costs associated with power supply to be delivered under the Department's Priority Long-Term Power Contracts ("PLTPCs");

(2) Operating reserves as determined by the Department (see Table A-1);

(3) Administrative and general expenses; and

(4) Ancillary Services.

Power Charge revenues include:

(1) Revenues from other power sales;

(2) Interest earnings; and

(3) Power Charge revenues (including both Power Charge Revenues and Direct Access Power Charge Revenues, as those terms are defined in the Bond Indenture).

There are no provisions included in Department Costs for the procurement of the residual net short by the Department during 2004.

During 2004, the Department projects that it will incur the following Department Costs: (a) $4.794 billion for long-term power contract purchases to cover the net short requirement of customers; (b) $59 million in administrative and general expenses; (c) $71 million in extraordinary expenses; and (d) $(108) million in other net changes to Power Charge Accounts. This results in a total of $4.816 billion in Department Costs.

Funds to meet these costs (in addition to surplus operating reserves) are provided from (a) $134 million from the Department's share of power sales revenues to the spot market; (b) $31 million of interest earned on Power Charge Account balances; and (c) $4.652 billion from Power Charges Revenues and Direct Access Power Charge Revenues.

Table C-1 provides a quarterly projection of costs and revenues associated with the Power Charge Accounts for the 2004 Revenue Requirement Period.

TABLE C-1
RETAIL REVENUE REQUIREMENT BASE CASE:
POWER CHARGE ACCOUNTS

Line	Description	Amounts for 2004 Revenue Requirement				
		Q1	Q2	Q3	Q4	Total
1	*Power Charge Accounts Expenses*					-
2	Power Costs	1,169	1,035	1,366	1,224	4,794
3	Administrative and General Expenses	15	15	15	15	59
4	Extraordinary Cost	71	-	-	-	71
5	Debt Service	-	-	-	-	-
6	Net Transfers from/(to) Bond Charge Accounts	-	-	-	-	-
7	Net Changes to Power Charge Account Balances	(62)	20	(134)	68	(108)
8	**Total Power Charge Accounts Expenses**	**1,192**	**1,070**	**1,247**	**1,307**	**4,816**
9	*Power Charge Accounts Revenues*					
10	Surcharge Revenues	-	-	-	-	-
11	Other Power Sales Revenues	39	23	30	42	134
12	Interest Earnings on Power Charge Account Balances	11	-	20	-	31
13	Net Loan Proceeds	-	-	-	-	-
14	Retail Customer Power Charge Revenue Requirement[1]	1,142	1,048	1,197	1,265	4,652
15	**Total Power Charge Accounts Revenues**	**1,192**	**1,070**	**1,247**	**1,307**	**4,816**

[1]Includes extraordinary receipts. See Table A:1 line 9.

Bond Related Costs include:

(5) Debt service on the Bonds (including related Qualified Swap payments);

(6) credit enhancement and liquidity facilities charges, and costs relating to other financial instruments and servicing arrangements relative to the Bonds, and

(7) Changes to Bond Charge Account balances.

Bond Related Revenues include:

(8) Interest earned on Bond Charge Account balances;

(9) Transfers from Power Charge Accounts; and

(10) Bond Charge Revenues (including from customers of Electric Service Providers).

Table C-2 provides a quarterly projection of costs and revenues relating to the Bond Charge Accounts for the 2004 Revenue Requirement Period.

TABLE C-2
POWER PURCHASE PROGRAM, REVENUE REQUIREMENT BASE CASE:
RETAIL CUSTOMER BOND CHARGE CASH REQUIREMENT

Line	Description	Amounts for 2004 Revenue				
		Q1	Q2	Q3	Q4	Total
1	*Bond Charge Accounts Expenses*					
2	Debt Service Payments	36	419	36	235	725
3	Other Bond Charge Account Expenses	-	-	-	-	-
4	Net Changes to Bond Charge Account Balances	171	(231)	209	(23)	126
5	**Total Bond Charge Accounts Expenses**	**206**	**188**	**245**	**212**	**852**
6	*Bond Charge Accounts Revenues*					
7	Interest Earnings on Bond Fund Balances	6	-	26	-	32
8	Revenue Bonds Net Proceeds	-	-	-	-	-
9	Net Transfers from/(to) Power Charge Accounts	-	-	-	-	-
10	Retail Customer Bond Charge Revenue Requirement	200	188	219	212	820
11	**Total Bond Charge Accounts Revenues**	**206**	**188**	**245**	**212**	**852**

During the 2004 Revenue Requirement Period, the Department projects that it will incur the following Bond Related Costs: (a) $725 million for debt service on the Bonds and related Qualified Swap payments, payments of credit enhancement and liquidity facilities charges, and costs relating to other financial instruments and servicing arrangements relative to the Bonds, and (b) $126 million for changes to Bond Charge Account balances, resulting in total Bond Charge Account expenses of $852 million.

Funds to meet these requirements are provided from (a) $32 million in interest earned on Bond Charge Account balances and (b) $820 million from Bond Charge Revenues (including from customers of Electric Service Providers). There are no projected net transfers from Power Charge Accounts.

In aggregate, the Department's total cash basis expenses are $5.650 billion. Revenues from interest earned and other power sales are $196 million, net changes in fund balances are $(18), resulting in combined customer revenue requirements of $5.472 billion.

D. Assumptions Governing the Department's Projection of Revenue Requirements for the 2004 Revenue Requirement Period

This 2004 Proposed Determination is based on a number of assumptions regarding sales, power supply, natural gas prices, off-system sales, demand side management and conservation, and administrative and general expenses.

Load and Sales Forecast

The Department obtained the most recent forecasts of customer loads from each IOU in April 2003. The forecasts received from the IOUs were compared with other relevant sources including recorded IOU sales data, forecasts prepared by the California Energy Commission ("CEC"), and the Western Electricity Coordinating Council ("WECC"). A loss factor was applied to the IOU estimates of sales at the customer's meter to obtain the total amount of energy required to meet customer electricity requirements. The loss factors utilized in developing the estimate of the electricity requirements were as follows.

TABLE D-1
LOSS FACTORS UTILIZED

Utility	Distribution	Transmission	Total
PG&E	7.0%	2.0%	9.0%
SCE	7.4%	1.6%	9.0%
SDG&E	4.0%	1.8%	5.8%

Each IOU forecast was developed using econometric models. The models rely on a statistical analysis of historical data to develop regression equations that relate changes in "independent" variables (such as employment growth) to "dependent" variables (such as electricity sales by end-user segment). The resulting equations, together with forecasts of electricity prices, weather conditions, and key economic drivers, are used to predict sales by revenue class. To improve accuracy, the projections may be modified by the IOUs to account for current trends, judgment, or other events not specifically addressed in the models.[4]

Table D-2 presents the major assumptions employed in the IOU forecasts utilized by the Department for the purpose of this 2004 Proposed Determination. The economic forecast for PG&E was based on a forecast of economic growth in PG&E's service area prepared by Economy.com. SCE derived its economic assumptions from a national and statewide forecast prepared by Data Resources Inc. ("DRI"), while SDG&E" relied on a DRI forecast of economic trends in its service area.

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4 The IOUs' load forecasts and forecasting models have received detailed scrutiny in numerous regulatory proceedings over the years. In addition to scrutiny by the Commission, the Federal Energy Regulatory Commission ("FERC"), and numerous regulatory interveners, the Commission's Office of Ratepayer Advocates customarily reviews and critiques the IOUs' forecasts based on its own independent load forecasts using its own econometric models. Typically, the differences between the IOUs' forecasts and those prepared by the Office of Ratepayer Advocates have been small. The high level of scrutiny of these forecasts by regulatory agencies and the acceptance of the projections for revenue allocation and rate setting purposes provide support for the reasonableness of the IOUs' forecasting efforts.

TABLE D-2
MAJOR ASSUMPTIONS USED IN THE LOAD FORECASTS OF THE INVESTOR-OWNED UTILITIES

	PG&E	SCE	SDG&E
Growth Assumptions:			
Population Growth[1]	1.0	1.8	1.4[3]
Number of Households[1]	1.3	1.0	1.7[3]
Non-Farm Employment[1,2]	1.0	1.1	2.1[3]
Heating Degree Days	20-Yr. Avg.	30-Yr. Avg.	20-Yr. Avg.
Cooling Degree Days	20-Yr. Avg.	30-Yr. Avg.	20-Yr. Avg.

Source: PG&E data from work papers submitted in PG&E's Notice of Intent for its 2003 GRC. SCE data from Notice of Intent for Test Year 2003 GRC. SDG&E data provided by the IOU.
[1] Percent per year increase during 2002 and 2003, except as noted.
[2] Actual growth during 2001 was 1.2 percent statewide, according to the State Department of Finance.
[3] Average annual percent growth from 2000 through 2006.

Sources of IOU Forecasts

The Department obtained from each IOU the load forecast used in the utility long-term resource plans, filed with the Commission on April 15, 2003. PG&E projects 2004 total retail sales of 85,822 GWh, SCE projects total retail sales of 90,035 GWh, and SDG&E projects total retail sales of 20,390 GWh. These projections include transmission and distribution losses.

Hourly Load Shapes

The Department utilized total retail and Direct Access hourly load shapes provided by each of the IOUs in 2002. Hourly energy and peak usage was estimated by applying percentage of sales in each hour to annual energy estimates provided by the IOUs.

Self-Generation

To determine the outlook for self-generation, the Department prepared a forecast of the potential increase in self-generating capacity in the IOU service areas. The forecast considered a range of factors including: (a) self-generation and/or renewable resource incentive programs and initiatives administered by the CEC, the Commission, the CPA, and the CAISO; (b) recent price increases, cost responsibility surcharges, the suspension of Direct Access, increased concerns over service reliability, and ongoing efforts to standardize interconnection requirements through the Commission's Rule 21 proceedings; and (c) potential barriers and market restraints to the expansion of self-generation. The forecasted self-generation is presumably incorporated in the IOU forecasts. Therefore, the estimate of self-generation does not result in a net reduction in energy and demand requirements compared with the forecasts prepared by the IOUs. Trends in self-generation capacity will be monitored and these assumptions will be revisited if warranted.

Direct Access

Direct Access was suspended as of September 20, 2001 by Commission Decision 02-03-055. Electric end-users who elected to acquire electricity supplies from alternative providers on or before September 20, 2001 and have not since returned to bundled service, continue to be eligible for Direct Access service. Decision 02-03-055 ordered the following:

- Suspends new Direct Access until the Department is no longer providing power to customers.
- Prohibits the IOUs from accepting any new Direct Access Service Requests not already approved by the Commission, including requests from existing qualified Direct Access end-users that wish to add new Direct Access locations or accounts to their service.[5]
- Contemplates the possible establishment by the Commission, at a future date, of a charge on Direct Access customers ("Direct Access Charge"). The Direct Access charge will be set at a level that prevents cost shifting as a result of Direct Access.

In Decision 02-11-022 the Commission ordered certain classes of Direct Access customers to pay a cost responsibility surcharge ("CRS"). The CRS was capped at 2.7 cents per kWh and includes one or more of the following charges, depending upon the customer:

- DWR Bond Charge: debt service costs associated with the Department's 2001 undercollection of power costs.
- DWR Power Charge: incremental costs to bundled customers resulting from the migration of load to Direct Access after July 1, 2001.
- Tail Competition Transition Charge ("CTC"): qualifying, uneconomic utility retained generation costs.
- HPC: historical procurement charge for year 2000 undercollection of power costs. Currently, this is only for SCE customers.

On May 8, 2003, the Commission issued Decision 03-05-034 regarding rules as to the right of customers to switch between Direct Access and bundled service on an ongoing basis. The Decision provides customers who were on Direct Access after September 20, 2001, but returned to bundled service subsequently, a 45-day safe harbor to return to Direct Access service. Under such circumstances, they will pay the applicable CRS component charges.

[5] However, these customers may renew their Direct Access service contracts upon their expiration or transfer them to a new service location as long as the load served is of comparable size.

Returning Direct Access customers who remain on bundled service beyond the 45-day safe harbor will be required to make a three year commitment to the IOU.

Direct Access customers may elect to return to bundled service but must provide the IOU six months advance notice, and must likewise make a three year commitment to the IOU. In the event customers return within the six month waiting period, they will pay the IOUs spot price of energy. They will also be responsible for their share of any CRS undercollection incurred while they were Direct Access customers.

On July 10, 2003, the Commission adopted Decision 03-07-030, which maintains the current CRS cap adopted by Decision 02-11-022.

Based on the above, the Department expects Direct Access to remain at a constant level statewide in 2004. The Department's Direct Access estimates, which are based on data provided by the Utilities in April 2003, are as follows.

TABLE D-3
DIRECT ACCESS PERCENT OF LOAD

	Percentage of Total Load
Pacific Gas and Electric Company	10.1%
Southern California Edison Company	14.0%
San Diego Gas and Electric Company	16.6%
Statewide	**12.6%**

PG&E Sales to Western Area Power Administration ("WAPA")

Contract 2948A, signed in 1967, governs the interconnection of PG&E's and WAPA's transmission and distribution systems and the integration of their loads and resources. The contract allows WAPA to integrate PG&E's fossil-fueled and other generating resources with the hydropower resources of the federal Central Valley Project ("CVP") and deliver this "firmed" energy to preference power customers—generally government and municipal entities—pursuant to Federal reclamation law. In return, PG&E receives access to surplus CVP hydroelectric generation which is less expensive than other resources available to PG&E. Virtually all of WAPA's 73 preference power customers are located in the PG&E service region in northern California.

During 2004, PG&E is assumed to provide 4,467 GWh of firming energy to WAPA. The forecast is based on WAPA's March 29, 2002 rolling 12-month forecast of preference power customer loads and the long-term average of CVP hydroelectric generation and U.S. Bureau of Reclamation pumping requirements contained in WAPA's July 2000 Green Book for the Post-2004 Marketing Plan. The Department also forecasts that WAPA will purchase 86 GWh of spot market energy during hours when the NP 15 price is projected to be lower than the cost of firming energy from PG&E. These spot market purchases reduce the amount of firming energy provided by PG&E.

The Department modeled PG&E sales to WAPA in PROSYM as a "negative bilateral" that reduces PG&E's Utility Retained Generation ("URG") and thereby increases the quantity of energy supplied by the Department. The sale is modeled as a base load contract and the peak MW for each month is computed by dividing the monthly energy by the number of hours in the month. Although this may somewhat overstate the peak MW provided to WAPA during the summer months, the impact on the Department's overall revenue requirement is not expected to be material. There are no comparable "other load requirements" for the other IOUs.

Contract 2948A expires at the end of 2004. The Department has assumed that this contract will not be renewed or replaced with another, similar contract.

Peak Load and Energy Calculations

Table D-4 provides the peak megawatt demand forecast for each IOU in 2004. Based on their respective load shapes, the total peak demand for PG&E, SCE and SDG&E occur in August 2004. The total IOU peak demand is the sum of the individual peaks. Due to load diversity, the coincident peak computed in PROSYM and experienced under actual conditions is likely to be lower.

TABLE D-4
ESTIMATED PEAK DEMAND[6]

	Amounts for the Revenue Requirement Period (Megawatts)
Pacific Gas and Electric Company	
Peak Demand[7]	17,591
Less Direct Access	1,137
Peak Demand After Adjustments[8]	16,454
Southern California Edison Company	
Peak Demand	19,278
Less Direct Access	2,305
Peak Demand After Adjustments	16,973
San Diego Gas and Electric Company	
Peak Demand	4,005
Less Direct Access	470
Peak Demand After Adjustments	3,535
All Investor-Owned Utilities	
Peak Demand	40,874
Less Direct Access	3,912
Peak Demand After Adjustments[9]	36,962

Table D-5 shows the estimated gigawatt hours of energy requirements expected during 2004.

6 All values presented in the table have been adjusted for transmission and distribution losses. .
7 Includes adjustments due to price elasticity effects.
8 For all three IOUs, these amounts are intended to represent peak demands that must be met by electric generating resources or power purchases or a combination of the two.
9 Represents the sum of the individual IOU amounts. The actual value at the time of the system's coincident peak may be lower.

TABLE D-5
ESTIMATED ENERGY REQUIREMENTS[10]

	Amounts for the Revenue Requirement Period (Gigawatt-Hours)
Pacific Gas and Electric Company[11]	
Energy Requirements[12]	85,822
Less Direct Access	8,646
Energy Requirements After Adjustments[13]	77,176
Southern California Edison Company	
Energy Requirements	90,035
Less Direct Access	12,579
Energy Requirements After Adjustments	77,456
San Diego Gas and Electric Company	
Energy Requirements	20,390
Less Direct Access	3,378
Energy Requirements After Adjustments	17,012
All Investor Owned Utilities	
Energy Requirements	196,247
Less Direct Access	24,604
Energy Requirements After Adjustments	171,643

Power Supply Related Assumptions

Two types of power supplies needed to meet the requirements of the three IOUs were considered by the Department in this 2004 Proposed Determination: (a) Supply from Priority Long-Term Power Contracts and (b) the residual net short of the three IOUs.[14]

Table D-6 below shows, for the 2004 Revenue Requirement Period, the estimated peak demand for each of the three IOUs, the estimated peak demand after adjustments, estimated supplies from generation retained by the three IOUs,[15] the resulting net short, the expected supply from the Department's Priority Long-Term Power Contracts, and the residual net short.

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[10] All values presented in the table have been adjusted for transmission and distribution losses.

[11] Amounts shown exclude 4,467 GWh of requirements associated with the company's contract with the Western Area Power Administration ("WAPA").

[12] For all three utilities, includes adjustments on account of price elasticity effects.

[13] For all three IOUs, these amounts are intended to represent energy requirements that must be met by electric generating resources or power purchases or a combination of the two.

[14] While the Department has calculated and presented the residual net short requirements of the IOUs, pursuant to AB1X, the Department has not made any provision for the cost of the residual net short requirements in its Determination for the 2004 Revenue Requirement Period.

[15] For purposes of this Determination, generation retained by the three IOUs is defined as the sum of generation owned by the IOUs, interruptible load, supply from contracts between the IOUs and qualifying facilities ("QF's") and other bilateral contracts.

TABLE D-6
ESTIMATED NET SHORT PEAK DEMAND, CAPACITY FROM PRIORITY LONG-TERM POWER CONTRACTS AND THE DEPARTMENT'S ESTIMATE OF THE RESIDUAL NET SHORT CAPACITY

	Amounts for the Revenue Requirement Period (Megawatts)
Pacific Gas and Electric Company	
Peak Demand[16]	17,591
Peak Demand After Adjustments	16,454
Supply from Utility Resources	10,211
Net Short	6,243
Supply from the Department's Priority Long Term Power Contracts	4,657
Residual Net Short (Surplus)	1,586
Southern California Edison Company	
Peak Demand	19,278
Peak Demand After Adjustments	16,973
Supply from Utility Resources	11,392
Net Short	5,581
Supply from the Department's Priority Long-Term Power Contracts	4,565
Residual Net Short (Surplus)	1,015
San Diego Gas and Electric Company	
Peak Demand	4,005
Peak Demand After Adjustments	3,535
Supply from Utility Resources	1,029
Net Short	2,506
Supply from the Department's Priority Long-Term Power Contracts	2,656
Residual Net Short (Surplus)	(151)

Table D-7 below presents similar information for the three IOUs in terms of energy requirements during the 2004 Revenue Requirement Period.

[16] See the discussion under "Load and Sales Forecast Assumptions" for an explanation of the source of data on peak demand for each of the three IOUs.

TABLE D-7
ESTIMATED NET SHORT ENERGY, SUPPLY FROM PRIORITY LONG-TERM POWER CONTRACTS AND THE DEPARTMENT'S ESTIMATE OF THE RESIDUAL NET SHORT

	Amounts for the Revenue Requirement Period (Gigawatt-Hours)
Pacific Gas and Electric Company	
Energy Requirements After Adjustments	77,176
Supply from Utility Resources	48,416
Net Short	28,760
Supply from the Department's Priority Long Term Power Contracts	23,234
Off-System Sales[17]	1,536
Residual Net Short (Surplus)[18]	7,062
Southern California Edison Company	
Energy Requirements After Adjustments	77,456
Supply from Utility Resources	62,368
Net Short	15,088
Supply from the Department's Priority Long Term Power Contracts	28,760
Off-System Sales	14,341
Residual Net Short (Surplus)	669
San Diego Gas and Electric Company	
Energy Requirements After Adjustments	17,012
Supply from Utility Resources	6,912
Net Short	10,100
Supply from the Department's Priority Long Term Power Contracts	7,617
Off-System Sales	254
Residual Net Short (Surplus)	2,738

For informational purposes, Table D-8 shows, for the 2004 Revenue Requirement Period, the expected average cost (in $/MWh) on a quarterly basis for the Department's Priority Long Term Power Contracts.

[17] Represents the aggregate energy sold into the wholesale market as a result of economic and must-take dispatch of resources.
[18] There is a difference in the GWh of Residual Net Short shown here for each of the IOUs compared to that included in the Financial Model. This is due to a calculation process in PROSYM relating to hourly vs. monthly roll-up of numbers. The total difference for all three IOUs is 380 GWh.

TABLE D-8
ESTIMATED POWER SUPPLY COSTS
(Dollars per Megawatt-Hour)

	Long-Term Priority Contracts
Quarter 1 – 2004	80
Quarter 2 – 2004	84
Quarter 3 – 2004	82
Quarter 4 – 2004	80

Table D-9 shows, on a quarterly basis for the 2004 Revenue Requirement Period, estimated net short volumes in gigawatt-hours, supply from Priority Long-Term Power Contracts, and the residual net short.

TABLE D-9
NET SHORT, SUPPLY FROM PRIORITY LONG-TERM POWER CONTRACTS, OFF-SYSTEM SALES AND RESIDUAL NET SHORT IN 2004

Period	Net Short (GWh)	Supply from Long-Term Priority Contracts (GWh)	Priority Long-Term Power Contract Costs (Millions of Dollars)	Off System Sales Volumes (GWh)	Revenues from Off System Sales (Millions of Dollars)	(Residual Net Short) Spot Volume (GWh)
Q1-2004	11,856	14,253	$1,128	(4,348)	$112	1,950
Q2-2004	11,395	13,478	1,110	(3,725)	82	1,642
Q3-2004	16,067	16,367	1,325	(3,118)	85	2,818
Q4-2004	14,629	15,512	1,225	(4,940)	149	4,057
Total	53,948	59,611	$4,787	(16,131)	$428	10,468

Natural Gas Price-Related Assumptions

Natural gas prices have undergone an upward shift in the price curve beginning in mid-2000. As a result of a combination of factors including supply availability, pipeline constraints, storage levels and weather patterns, natural gas prices have risen above a price band that lasted for most of the previous decade. The "California crisis" in early 2001 also contributed to sustained increases in natural gas prices.

For the gas price forecast underlying this 2004 Proposed Determination (the same gas price forecast was used for the 2003 Supplemental Determination), there have been adjustments from the forecast used in the August 16, 2002 Determination. The first adjustment in January 2003 began with a starting price approximately $1.00 per MMBtu higher than the previous price forecast. The base forecast also incorporated an adjustment to another key variable, weather. Based upon the record warm winter in 2002 (January - March 2002), the prior forecast used about 10 percent fewer degree days than normal, in anticipation that total 2002 degree days would remain lower than normal. The 10 percent fewer degree days had the impact of reducing the previous price forecast by $0.30 per MMBtu from what it would have been with normal weather. The third key change in the current price forecast was to recalibrate the drilling variable. The drilling variable accounts for the number of wells that need to be completed in order to produce sufficient natural gas to meet projected demand. Recalibrating the well depletion assumptions behind the drilling variable results in an additional 1,800 wells being required in almost all forecast years and increasing the price by approximately $0.43 per MMBtu.

Nationally, the winter of 2003 was one of the coldest winters on record, particularly in the Northeast consuming region. The cold weather, combined with abnormally strong storage withdrawal volumes, resulted in low storage levels and contributed to much higher than anticipated short-term prices during the first quarter of 2003, with lingering price effects thereafter. The March monthly index price of $9.11 per MMBtu, for example, was much higher than anticipated ($3.81 per MMBtu was the forcasted price) and had the effect of potentially skewing the entire 2003 year forecast. In March, an extraordinary adjustment to the January 2003 price forecast was prepared that adjusted short term prices experienced in the first quarter to actual prices and "shaped" the balance of the spring shoulder and summer prices. These prices were then re-run using the Department's proprietary long term price forecasting model. The model relates annual natural gas prices to prior period prices, reflects weather as average heating or cooling degree days and utilizes a variable for drilling activity and well completions to produce a forward price at Henry Hub. Not surprisingly, these changes had the greatest impact upon near term prices with the annual price for 2003 increasing by $1.07 per MMBtu from the previous forecast. For the following years, the price changes are projected to be less significant, increasing by $0.31 per MMBtu in 2004 and $0.11 per MMBtu in 2005. By 2006 the short-term effects of the winter of 2003 prices are expected to have no effect on the previous forecast.

Prices at Henry Hub determined by the model are then adjusted by adding a "basis" differential to the Henry Hub price to arrive at the Southern California Border. Delivered prices in California are determined by adding the cost of intrastate transport to the California border price. Resulting gas prices for 2003 and 2004 at the Southern California Border, Malin and PG&E's city-gate are shown in Table D-10.

TABLE D-10
NATURAL GAS ASSUMPTIONS
(Dollars per MMBtu)

	Socal Border	Malin	PG&E City Gate
2003	5.17	4.86	5.26
2004	4.37	4.09	4.45

Hydro Condition Assumptions

Normal hydro conditions are assumed for both California and the Pacific Northwest for 2004 and 2005. At the time of this writing, the CEC was finalizing its California Hydro-Electricity Outlook report for 2003[19]. The CEC has indicated it expects nearly 108 percent of normal hydro conditions for 2003, due primarily to a very wet April 2003. The CEC also indicated that hydrological conditions for 2003 were improving in the Pacific Northwest, but had not returned to completely normal conditions. Additional sources were checked, which showed information consistent with the CEC. Due to the difficulty of predicting hydrologic conditions, and given the above information, it is reasonable to assume normal hydrologic conditions for the 2004 Revenue Requirement Period.

Sales of Excess Energy Assumptions

As with any retail provider of energy, the Department and IOUs together, from time to time, purchase more energy than is needed to serve their retail customers. This excess energy is sold in wholesale markets. The income from such sales is used to partially offset the revenue requirements of the Department and the IOUs which would otherwise be recovered from retail customers.

On September 19, 2002, the Commission issued Decision 02-09-053, Interim Opinion on Procurement Issues: DWR Contract Allocation. This Decision allocated each of the thirty-five PLTPCs to a specific IOU. Decision 02-09-053 also determined that income from the sale of excess energy (off-system sales) would be shared between the Department and the IOUs.

The Department's share of revenue from the sale of excess energy from the PLTPCs is provided in Table D-11 below.

[19] 5/29/03 telephone call to CEC's Jim Woodward, principle author of the CEC's California Hydro-Electricity Outlook report for 2003.

TABLE D-11
SALE OF EXCESS ENERGY

	Excess Energy Sales Volume (GWh)	Excess Energy Sales Revenue (Millions of Dollars)	Weighted Average Price ($/MWh)
Q1 – 2004	1,399	37	26
Q2 – 2004	1,085	25	23
Q3 – 2004	1,003	29	29
Q4 – 2004	1,656	52	31
Total	5,142	143	28

Extraordinary Costs

In 2004, the Department has identified, as a separate line item, cash collateral provided in connection with gas purchases, previously included within Power Costs. The Department analyzed the NYMEX margin requirements to secure futures on the highest seven months of fuels requirements. Margin requirements of the NYMEX exchange are listed by the exchange. The margins are exchange requirements based upon a fixed price per contract. In order to come up with a total margin cost, anticipated fuel volumes from June through December 2004 were utilized. These anticipated fuel volumes are determined through the use of the production simulation analysis that underlies this 2004 Proposed Determination. Based upon these volumes, margin requirements to purchase futures for the fuels program from June through December 2004 would be $71 million. This amount is comparable to the 2003 collateral requirement of $54 million.

Contract Assumptions

Table D-12 provides a listing of all of the long-term energy contracts and describes the term and capacity associated with each contract and the IOU to which the contract has been assigned. (Information related to the recently completed Allegheny Energy renegotiation is not included in table D-12, though it is included in PROSYM data. This renegotiation resulted in no material change in 2004). More detailed contract terms can be found on the CERS website, http://cers.water.ca.gov.

TABLE D-12
LONG TERM CONTRACT LISTING

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Assigned
Allegheny Energy Supply Company, LLC	3/23/2001	3/23/2001	3/31/2001	150	N/A
"	" "	4/1/2001	6/30/2001	750	N/A
"	" "	7/1/2001	9/30/2001	250	N/A

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Assigned
"	" "	10/1/2001	12/31/2003	250	SCE
"	" "	1/1/2004	12/31/2004	500	SCE
"	" "	1/1/2005	12/31/2011	1000	SCE
"	4/20/2001	1/1/2003	12/31/2003	150	PG&E
Alliance Colton LLC	4/23/2001 Renegotiated on 9/19/02	8/1/2001	12/31/2010	80	SCE
BPA	2/16/2001	2/16/2001	12/31/2001	TBD	N/A
"	2/9/2001	2/13/2001	4/30/2002	18 MW	N/A
CalPeak Power-- Midway LLC (moving to a new site)	8/14/2001 Renegotiated on 5/2/02	Upon COD, est. 8/03	8/1/2012	49	PG&E
CalPeak Power-- Panoche LLC	8/14/2001 Renegotiated on 5/2/02	12/27/2001	12/27/2011	50	PG&E
CalPeak Power--Vaca Dixon LLC	8/14/2001 Renegotiated on 5/2/02	6/21/2002	12/31/2011	48	PG&E
CalPeak Power-- El Cajon LLC	8/14/2001 Renegotiated on 5/2/02	5/29/2002	12/31/2011	48	SDG&E
CalPeak Power--Border LLC	8/14/2001 Renegotiated on 5/2/02	12/12/2001	12/12/2011	48	SDG&E
CalPeak Power-- Enterprise LLC	8/14/2001 Renegotiated on 5/2/02	12/8/2001	12/8/2011	48	SDG&E
CalPeak Power-- Mission LLC	8/14/2001 TERMINATED on 5/2/02			Was 48	N/A
Calpine Energy Services, L.P. (Firm)	2/6/2001 Renegotiated on 4/22/02	10/1/2001	12/31/2001	200	N/A
"	"	1/1/2002	12/31/2002	350	N/A
"	"	1/1/2003	12/31/2003	600	PG&E
"	"	1/1/2004	12/31/2009	1000	PG&E
"	Added by 4/22/02 Renegotiation	5/1/2002	5/31/2002	200	N/A
"	"	6/1/2002	6/30/2002	50	N/A
"	"	7/1/2002	5/31/2003	650	PG&E
"	"	6/1/2003	12/31/2003	400	PG&E
"	"	5/1/2002	12/31/2003	400	PG&E
Calpine Energy Services, L.P. (Long Term Commodity Sale)	2/26/2001 Renegotiated on 4/22/02	7/1/2001	12/31/2001	200	N/A
"	"	1/1/2002	6/30/2002	200	N/A
"	"	7/1/2002	12/31/2009	1000	PG&E
"	Added by 4/22/02 Renegotiation	5/1/2002	6/30/2002	800	N/A
"	"	6/1/2002	12/31/2002	500	N/A

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Assigned
"	"	6/1/2003	9/30/2003	500	PG&E
"	"	5/1/2002	12/31/2003	400	PG&E
Calpine Energy Services, L.P. (Peaking Capacity)	2/27/2001 Renegotiated on 4/22/02	8/1/2001	11/30/2001	90	N/A
"	"	12/1/2001	1/31/2002	135	N/A
"	"	6/1/2002	7/31/2002	450	N/A
"	"	8/1/2002	7/31/2011	495	PG&E
Calpine Energy Services, L.P. (North San Jose Project)	6/11/2001 Renegotiated on 4/22/02	3/6/2003	3/04	180	PG&E
"	"	Upon COD, est 3/2004	3/6/2006	225	PG&E
Capitol Power, Inc.	8/23/2001 Renegotiated on 3/8/02; TERMINATED on 11/15/02			Was 15	N/A
Clearwood Electric Company, LLC	6/22/2001 Renegotiated on 11/20/02	Upon COD, est 7/05	12/31/2012	25 to 30	PG&E
Constellation Power Source, Inc.	3/9/2001 Renegotiated on 4/22/02	4/1/2001	6/30/2003	200	SCE
"	Added by 4/22/02 Renegotiation	5/1/2002	10/31/2002	400	N/A
"	"	5/1/2003	10/31/2003	400	PG&E
Coral Power, LLC	5/24/2001	5/24/2001	6/30/2001	100	N/A
"	"	7/1/2001	7/31/2001	150	N/A
"	"	8/1/2001	8/31/2001	250	N/A
"	"	9/1/2001	9/30/2001	325	N/A
"	"	10/1/2001	6/30/2002	200	N/A
"	"	7/1/2002	6/30/2003	300	PG&E
"	"	7/1/2003	12/31/2003	400	PG&E
"	"	1/1/2004	12/31/2005	400	PG&E
"	"	1/1/2006	6/30/2010	400	PG&E
"	"	7/1/2010	6/30/2012	100	PG&E
"	"	7/1/2002	6/30/2012	100	PG&E
"	"	7/1/2003	6/30/2012	175	PG&E
"	"	7/1/2004	6/30/2012	175	PG&E
Dynegy Power Marketing, Inc.	3/2/2001	3/6/2001	12/31/2001	1000	N/A
"	"	3/6/2001	12/31/2001	200 (off-pk only)	N/A
"	"	1/1/2002	12/31/2004	500-1500	SCE

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Assigned
"	"	1/1/2002	12/31/2004	200-1500 (off pk only)	SCE
"	"	1/1/2002	12/31/2004	200	SCE
"	"	1/1/2002	12/31/2004	600	SCE
El Paso Merchant Energy	2/13/2001	2/9/2001	12/31/2005	50	SCE
"	"	"	"	50	PG&E
GWF Energy LLC	5/11/2001 Renegotiated on 8/22/02	9/6/2001	12/31/2011	88	PG&E
"	"	7/1/2002	12/31/2011	88	PG&E
"	"	Est. 6/03	10/31/2012	164	PG&E
High Desert Power Project	3/9/2001 Renegotiated on 4/22/02	4/22/2003	3/31/2011	Up to 840	SCE
Imperial Valley Resource Recovery Company, LLC ("Primary Power")	3/13/2001	6/1/2001	12/31/2003	16	SDG&E
InterCom	8/24/2001	1/1/2002	8/31/2003	200	PG&E
Mirant Americas Energy Marketing LP	5/22/2001	6/1/2001	12/31/2002	500	N/A
Morgan Stanley Capital Group	2/14/2001	2/15/2001	12/31/2005	50	SDG&E
PacifiCorp	7/6/2001	7/29/2001	6/30/2002	150	N/A
"	"	7/1/2002	12/31/2002	200	N/A
"	"	1/1/2003	6/30/2004	200	PG&E
"	"	7/1/2004	6/30/2011	300	PG&E
Pinnacle West	5/3/2001	5/3/2001	5/31/2001	100 (off pk only)	N/A
"	"	6/1/2001	6/30/2001	100 (off pk only)	N/A
"	"	7/1/2001	9/30/2001	100 (off pk only)	N/A
"	"	6/1/2001	9/29/2001	Varies (40 to 125 MW)	N/A
PG&E Energy Trading	5/31/2001 Renegotiated on 10/1/02	10/1/2001	9/30/2011	66.6	SCE

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Assigned
PX Block Forward	Seized	4/1/2001	6/30/2001	275 (aggregated)	N/A
"	Seized	7/1/2001	9/30/2001	500 (aggregated)	N/A
"	Seized	10/1/2001	12/31/2001	125 (aggregated)	N/A
"	Seized	4/1/2001	6/30/2001	500 (aggregated)	N/A
"	Seized	7/1/2001	9/30/2001	925 (aggregated)	N/A
"	Seized	10/1/2001	12/31/2001	450 (aggregated)	N/A
Santa Cruz County	9/13/2001 Renegotiated on 12/19/02	Upon COD, est 7/03	6/30/2007	2 to 3	PG&E
Sempra Energy Resources	5/4/2001	6/1/2001	9/30/2001	250	N/A
"	"	4/1/2002	9/30/2002	150	N/A
"	"	"	"	300	N/A
"	"	10/1/2002	5/31/2003	220	SCE
"	"	6/1/2003	12/31/2003	1000	SCE
"	"	1/1/2004	9/30/2011	1200; drops to 800 in Mar-May of 2004-2007	SCE
"	"	6/1/2003	12/31/2003	350	SCE
"	"	1/1/2004	9/30/2011	700; drops to 400 in Mar-May of 2004-2007, and permanently starting Jan 2008	SCE
Soledad Energy LLC	4/28/2001; terminated on 3/27/02; Revision Executed on 6/27/02	appr. 8/02	10/31/2006	13	PG&E
Sunrise Power Company, LLC	6/25/2001 Renegotiated on 12/31/02	7/16/2001	2/28/2003	325	SDG&E
"	"	Est. 8/03	6/30/2012	560	SDG&E
(Wellhead) Fresno Cogeneration Partners	8/3/2001 Renegotiated on 12/17/02	8/20/2001	10/31/2011	21.3	PG&E

Counter-Party	Date Executed	Delivery Start Date	Delivery End Date	Capacity MW	Assigned
Wellhead Power Gates, LLC	8/14/2001 Renegotiated on 12/17/02	12/27/2001	10/31/2011	46.5	PG&E
Wellhead Power Panoche, LLC	8/14/2001 Renegotiated on 12/17/02	12/14/2001	10/31/2011	49.9	PG&E
Whitewater Energy Corp. (Cabazon Project)	7/12/2001 Renegotiated on 4/24/02	8/31/2002	12/31/2013	43	SDG&E
Whitewater Energy Corp. (Whitewater Hill Project)	7/12/2001 Renegotiated on 4/24/02	8/31/02 (partial)	12/31/2013	65	SDG&E
Williams Energy Marketing & Trading	2/16/2001 Renegotiated on 11/11/02	6/1/2001	9/30/2001	35	N/A
"	"	10/1/2001	11/11/2002	40	N/A
"	"	1/1/2003	6/30/2003	40	SDG&E
"	"	7/1/2003	12/31/2007	200	SDG&E
"	"	4/1/2001	9/30/2001	175	N/A
"	"	10/1/2001	11/11/2002	200	N/A
"	"	1/1/2003	6/30/2003	175	SDG&E
"	"	7/1/2003	12/31/2005	450	SDG&E
"	"	1/1/2006	12/31/2006	450	SDG&E
"	"	1/1/2007	12/31/2007	450	SDG&E
"	"	1/1/2008	12/31/2008	275	SDG&E
"	"	1/1/2009	12/31/2009	275	SDG&E
"	"	1/1/2010	12/31/2010	275	SDG&E
"	"	6/1/2001	9/30/2001	140	N/A
"	"	10/1/2001	11/11/2002	160	N/A
"	"	7/1/2003	12/31/2010	50	SDG&E
"	Added by 11/11/2002 Renegotiation	1/1/2003	6/30/2003	430	SDG&E
"	"	7/1/2003	12/31/2007	1175	SDG&E
"	"	1/1/2008	12/31/2010	1045	SDG&E

Administrative and General Costs

The Department's administrative and general costs of $59 million included in Power Charges consist of $55 million included in the Department's appropriated budget plus $4 million for consulting services for development and monitoring of the revenue requirements, and financial advisory and related consulting services for managing the $11 billion debt portfolio and related reserves.

The proposed 2003-2004 State Budget currently has $55 million appropriated for the Department's power supply program. This includes funds for labor and benefits, professional service costs, including costs for litigation, and $28 million for pro-rata charges for services provided to the Power Supply program by other State agencies. The pro-rata charge includes $14 million that is retroactive to the 2001-2002 fiscal year and $14 million for the 2003-2004 fiscal year. The administrative budget has been presented to Legislative budget committees but will not be authorized until the State budget has been adopted and signed by the Governor.

Financing Related Assumptions

In October and November 2002, the Department issued $11.263 billion of Power Supply Revenue Bonds. The primary uses of net Bond proceeds were to (a) repay the then-outstanding balance of the $4.3 billion Interim Loan entered into by the Department with commercial lenders, the proceeds of which were used to fund 2001 power costs; (b) reimburse the State's General Fund for approximately $6.1 billion advanced to the Department for 2001 power purchases and interest that had accrued on the General Fund advances, and (c) fund reserves required to complete the bond financing.

The details of the Bond financing structure were made public in connection with the Department's 2003 Revenue Requirement filing and are described in the Bond Indentures and Supplemental Bond Indentures for each series of Bonds.

For purposes of calculating the interest earnings on all account balances, the Department assumes a 2.0 percent earnings rate for the 2004 Revenue Requirement Period.

The Department projects that the amount of Bond Charge Revenues required for the 2004 Revenue Requirement Period will be $820 million.

Accounts and Flow of Funds Under the Bond Indenture

The terms agreed to in the Rate Agreement and Summary of Material Terms with all applicable addenda are reflected in the Bond Indenture. The following is a description of the funds and accounts that are required as part of the Bond program.

Revenues are held in and accounted for in the Electric Power Fund established under AB1X. The Bond Indenture established two sets of accounts for Revenues within the Electric Power Fund. In the following description of accounts and the flow of funds, capitalized terms refer to terms that are further defined in the Indenture.

One set of accounts is primarily for the deposit of Power Charge Revenues and the payment of Operating Expenses (including payments of Priority Contract Costs and other power purchase costs and other costs of the Power Supply Program) (collectively, the "Power Charge Accounts"):

- The Operating Account,
- The Priority Contract Account,

- The Operating Reserve Account, and
- The Administrative Cost Account.

The other set of accounts is primarily for the deposit of Bond Charge Revenues and the payment of Bond Related Costs (collectively, the “Bond Charge Accounts”):

- The Bond Charge Collection Account,
- The Bond Charge Payment Account, and
- The Debt Service Reserve Account.

The Bond Indenture requires all Bond Charge Revenues to be deposited in the Bond Charge Collection Account and all Power Charge Revenues and other Revenues (other than Bond Charge Revenues) to be deposited in the Operating Account.

Operating Account

The Department has covenanted to include in its revenue requirements amounts sufficient to cause a Minimum Operating Expense Available Balance (“MOEAB”) to be on deposit in the Operating Account. The MOEAB is to be calculated by the Department at the time of each determination of a revenue requirement. The MOEAB for so long as the Department continued to purchase the residual net short, was to be an amount up to and including $1 billion, and thereafter is to be an amount equal to the largest projected difference between the Department's projected operating expenses and the Department's projected Power Charge revenues during any one month period during the then current revenue requirement period, taking into account a range of possible future outcomes (i.e., “stress cases”).

Responsibility for the procurement of the residual net short was transitioned to the IOUs effective the end of 2002.

For the purposes of this 2004 Proposed Determination, the MOEAB is determined by the Department to be $286 million

Priority Contract Account

The Priority Contract Account is used to pay the costs the Department incurs under its Priority Long Term Power Contracts, which have terms that require the Department to pay for power purchased under these contracts ahead of Bond Related Costs. On or before the fifth Business Day of each month, the Department is required to transfer from the Operating Account to the Priority Contract Account such amount as is necessary to make the amount in the Priority Contract Account sufficient to pay Priority Contract Costs estimated to be due during the balance of such month and through the first five Business Days of the next succeeding calendar month. Amounts in the Priority Contract Account may be used solely to pay Priority Contract Costs.

For the 2004 Revenue Requirement Period it is projected that the Priority Contract Account will have sufficient funds available from the Operating Account, and that no transfer from Bond Charge Collection Account to the Priority Contract Account will be required.

Operating Reserve Account

The Operating Reserve Account Requirement ("ORAR") is to be calculated, in respect of each Revenue Requirement Period, as the greater of (a) the largest aggregate amount projected by the Department by which Operating Expenses exceed Power Charge Revenues during any consecutive seven calendar months commencing in such Revenue Requirement Period and (b) either (i) 18 percent of the Department's projected annual Operating Expenses for any Revenue Requirement Period in which the Department is procuring all or a portion of the residual net short and which commences prior to 2006, or (ii) 12 percent of the Department's projected annual Operating Expenses for any Revenue Requirement Period in which the Department is not procuring all or a portion of the residual net short or which commences after 2005, provided, however, that solely for purposes of (b) above, for Revenue Requirement Periods commencing after 2003, the projected amount will not be less than the applicable percentage of Operating Expenses for the most recent 12-month period for which reasonably full and complete Operating Expense information is available, adjusted in accordance with the Indenture to the extent the Department no longer is financially responsible for any particular Power Supply Contract. All projections will be based on such assumptions as the Department deems to be appropriate after consultation with the Commission and, in the case of clause (i) above, may take into account a range of possible future outcomes (i.e., "stress cases").

With the successful transition of the residual net short procurement responsibility to the IOUs at the end of 2002, the ORAR is sized as the maximum seven-month difference between operating revenues and expenses as calculated under "stress" operating conditions (later described in the "Sensitivity Analysis" portion of Section D). The ORAR for the 2004 Revenue Requirement Period is determined by the Department to be $591 million.

Bond Charge Collection Account

All Bond Charge revenues will be deposited in the Bond Charge Collection Account. Subject to the prior claim on revenues in the Bond Charge Collection Account for the payment of costs under the Long-Term Priority Contracts, on or before the last Business Day of each month, the Department is required to transfer from the Bond Charge Collection Account to the Bond Charge Payment Account such amount as is necessary to make the amount in the Bond Charge Payment Account sufficient to pay Bond Related Costs (including debt service on the Bonds and all other Bond Related Costs) estimated to accrue or to be due and payable during the next succeeding three calendar months.

The minimum balance to be maintained from time to time within the Bond Charge Collection Account is determined to be an amount equal to one month's required deposit to the Bond Charge Payment Account. As required by the Bond Indenture, the Department assumes interest costs on unhedged Variable Rate Bonds during the 2004 Revenue Requirement Period at 4.0 percent for the purpose of calculating required deposits to the Bond Charge Payment Account. For the 2004 Revenue Requirement Period, the minimum account balance amount ranges from $75 to $78 million.

Bond Charge Payment Account

The Bond Charge Payment Account is calculated as an amount equal to the debt service accrued and unpaid through the end of the third next succeeding calendar month. The Department assumes interest costs on unhedged Variable Rate Bonds during the 2004 Revenue Requirement Period at 4.0 percent for the purpose of calculating debt service accruals in the Bond Charge Payment Account. For the 2004 Revenue Requirement Period, the minimum account balance amount ranges from $319 to $721 million.

Debt Service Reserve Account

The "Debt Service Reserve Requirement" is an amount equal to maximum aggregate annual debt service on all outstanding Bonds, determined in accordance with the Bond Indenture. The Debt Service Reserve Account is required by the Bond Indenture to be funded in the amount of the Debt Service Reserve Requirement, initially with proceeds from the sale of the Bonds (or Alternate Debt Service Reserve Account Deposits referred to below, or a combination of both) and subsequently maintained and replenished, if necessary, from Power Charge Revenues or Bond Charge Revenues

For purposes of calculating the amount of the Debt Service Reserve Requirement from time to time, interest accruing on Variable Rate Bonds during any future period will be assumed to accrue at a rate equal to the greater of (a) 130 percent of the highest average interest rate on such Variable Rate Bonds in any calendar month during the twelve (12) calendar months ending with the month preceding the date of calculation, or such shorter period that such Variable Rate Bonds shall have been Outstanding, or (b) 4.0 percent. For the 2004 Revenue Requirement Period, the Department will calculate projected interest on unhedged Variable Rate Bonds at 4.0 percent.

Alternate Debt Service Reserve Account Deposits may be made to the Debt Service Reserve Account in lieu of cash and/or securities. Such deposits may consist of irrevocable surety bonds, insurance policies, letters of credit or similar obligations. The Department is not currently assuming the use of Alternate Debt Service Reserve Account Deposits.

For the 2004 Revenue Requirement Period, the Debt Service Reserve Requirement is determined to be $927 million.

Sensitivity Analysis

The Rate Agreement requires the Department to evaluate its costs and cash flows on a monthly basis and to file revised Retail Revenue Requirements with the Commission no less than once each year, thereby ensuring that Bond Charges and Power Charges are adequate to meet financial obligations associated with the Bonds and the power supply program. From the date the Department first initiates a revised Retail Revenue Requirement proceeding, it expects no more than seven months will elapse before it receives modified levels of revenues associated with the filing. As explained in prior Department revenue requirement determinations, during this seven month period the Department would endeavor to identify any material changes in its revenue requirement, proceed through its own administrative determination of its modified revenue requirement, file and initiate the Commission process regarding the new revenue requirement and allocation of costs among customers, and finally begin receiving the modified level of revenue. In order to ensure its ability to meet its financial obligations during this seven month lag period, the Department must maintain reserves that are adequate to meet normal anticipated expenses, unexpected variations in these expenses, and/or reductions in revenue receipts resulting from factors beyond the Department's control. The determination of reserve levels is made by the Department considering such factors as the potential variations in revenue receipts and power supply program expenses, changes in key variables affecting customer energy requirements, URG production levels, changing natural gas prices, and Department contract operations, among other factors.

To assess the adequacy of reserve levels, the Department and its consultants have prepared an additional assessment of cash flow projections based on changes in certain key expense and operating assumptions ("Stress Cases"). The Stress Cases considered in this assessment reflect a sampling of groups of changes in key assumptions that could affect Department expenses and revenues. The Stress Cases are not intended to reflect all possible scenarios, nor are they intended to reflect only those most likely to occur. For the Stress Cases, a market simulation was performed to generate revised net short requirements and associated power supply costs. These revised forecasts were used to generate revised cash flow projections for the Department. These revised results were compared against the base estimate of cash flow projections (the "Base Case").

The Department comprehensively analyzed two Stress Cases in this Determination.

Case 1

This Stress Case focuses on decreased Bond Charge and Power Charge revenues resulting from lower sales to its customers, and increased costs of providing energy under existing contracts.

Higher costs are driven primarily by increased fuel costs. This Stress Case utilizes a natural gas price forecast that is double the level of the Base Case forecast. Lower customer sales by the Department are driven primarily by a decrease in the net short, which can occur as a result of increased URG and/or decreased customer load. In this case, URG is increased by assuming California and Pacific Northwest hydroelectric production at 115% of normal for 2004 and 2005.

Lower loads are estimated in this case by assuming cooler-than-normal summers during 2004 and 2005, and by assuming increased non-programmatic conservation. The level of decreased customer load due to temperature variation is simulated by decreasing the Base Case total monthly load forecast for 2004 and 2005 by 3% for June and July, and by 5% for August and September. In addition, an increase in the assumed level of non-programmatic conservation (above the Base Case) results in decreases in total annual load of 4% in 2004 and 2% in 2005. Lower electric loads result in a Stress Case for Department revenue because the fixed component of Department energy contracts must be allocated over fewer MWh of retail electric sales, thereby increasing the Department's required recovery cost per MWh.

Case 2
This Stress Case focuses on increased costs of providing energy under existing contracts, and considers increased contract dispatch due to higher customer load and reduced URG.

Higher costs are driven primarily by increased fuel costs. This Stress Case utilizes a natural gas price forecast that is double the level of the Base Case forecast. Higher customer sales by the Department are driven primarily by an increase in the net short, which can occur as a result of decreased URG and/or increased customer load. In this case, URG is decreased by assuming California and Pacific Northwest hydroelectric production at 75% of normal in 2004 and 2005. URG is further decreased by assuming an unplanned outage at one southern California nuclear power plant unit in the first quarter of 2004.

Higher loads are estimated in this case by assuming load growth rates that are 1.4% of total load higher than those assumed in the Base Case in 2004 and 1.3% higher in 2005. It is assumed that this growth occurs as a result of an accelerated economic recovery in California and decreases in the expected amount of non-programmatic conservation. In addition, load is increased by assuming the existence of warmer-than-normal summers in 2004 and 2005. The level of increased customer load due to temperature variation is simulated by increasing the Base Case total monthly load forecast (inclusive of the accelerated growth rates described above) in 2004 and 2005 by 3.2%, 3.6%, 5.4% and 4.6% for June, July, August and September respectively

E. Key Uncertainties In The Revenue Requirement Determination

There are a number of uncertainties facing the Department that may require material changes to its revenue requirements for the 2004 period after this initial determination. Several risk factors are outlined below and additional information may be found in each of the bond financing Official Statements, which may be obtained from the Treasurer of the State of California.

1. Determination of Power Charges and Bond Charges; possible use of amounts in the Bond Charge Collection Account to pay Priority Contract Costs
    a. Legal challenges to DWR's administrative process;
    b. Administrative and legal Challenges to DWR's revenue requirements;
    c. Litigation regarding inclusion of DWR Priority Contract Costs in its Retail Revenue Requirement;
    d. Application and enforcement of CPUC's Bond Charge rate covenant; and
    e. DWR's assessment of these risks.

2. Collection of Bond Charges and Power Charges

3. Bankruptcy risks
    a. Uncertainty as to outcome of PG&E bankruptcy;
    b. Potential rejection of Servicing Agreements or other disruption of servicing arrangements; and

c. Potential impact of PG&E bankruptcy proceedings on PG&E Servicing Order.

4. Certain risks associated with DWR's Power Supply Program
    a. Priority Long-Term Power Contracts
        i. Impact of renegotiated contracts
        ii. Off-System sales volume and price variability;
    b. Transition risks; and
    c. DWR administrative expenses appropriation by State Legislature

5. Potential increases in overall electric rates
    a. Changes in general economic conditions;
    b. Energy market-driven increases in wholesale power costs;
    c. Fuel costs;
    d. Hydro conditions and availability;
    e. Market manipulation;
    f. "Block Forward Contracts" consolidated actions;
    g. Action requiring DWR to pay for power ordered for PG&E and SCE;
    h. Actions affecting retail rates; and
    i. Impact of these factors.

6. Potential decrease in DWR customer base
    a. Direct Access; and
    b. Load departing IOU service

7. Uncertainties relating to electric industry and markets

8. Uncertainties relating to government action
    a. California Emergency Services Act;
    b. Possible State Legislation or action;
    c. Recent State Legislation; and
    d. Possible Federal Legislation or action.

F. Just and Reasonable Determination

The August 16, 2002 Determination

The August 16, 2002 Determination provided extensive material leading to the determination by the Department that its revenue requirement for 2003 as determined therein was just and reasonable. That information is, to the extent applicable and not modified herein, incorporated in this 2004 Proposed Determination by reference and will not be repeated herein.

The 2003 Supplemental Determination

Subsequent to August 16, 2002, new information became available to the Department. Such new information, either provided by the IOUs, as a result of experience from actual transactions, or emanating from a change in certain assumptions, led to the 2003 Supplemental Determination. The just and reasonable determination in the 2003 Supplemental Determination is, to the extent applicable and not modified herein, incorporated in this 2004 Proposed Determination by reference and will not be repeated herein.

The Department will make a Just and Reasonable Determination after Completion of its Administrative Process

The Department submits this 2004 Proposed Determination for public review under the Regulations promulgated pursuant to the California Administrative Procedures Act. Under the regulations promulgated by the Department, a final determination by the Department that the 2004 Proposed Determination is just and reasonable will only be made after the administrative process is complete and may result in the submittal of a 2004 Determination to the Commission that differs from this 2004 Proposed Determination.

G. Market Simulation

Wholesale power costs in the western United States are driven by a multitude of factors. These include weather and related electricity demand, precipitation and related hydropower production, supply and price of natural gas and coal, power transfer capability of major interties, operating costs, outages and retirement of generating plants, and the cost, fuel efficiency, and timing of new generating resource additions. The Department analyzed the fundamental drivers underlying the electricity market by generating computer simulations of market activity throughout the Western Electricity Coordinating Council ("WECC") region. PROSYM price forecasting and market simulation tool was used.

PROSYM is a widely accepted tool for simulating detailed power market activity and has a large market presence in the industry. According to its vendor, 80 percent of the major utilities in North America and many utilities in Europe, Asia, and Australia license PROSYM. It has been used to provide analytical support and to forecast market prices and revenues in a large number of financing transactions for merchant power plants and has gained strong acceptance in the financial community.

PROSYM is a detailed chronological model that simulates hourly operation of WECC generation and transmission resources. Within its simulation framework, PROSYM dispatches generating resources to match hourly electricity demand and establishes market-clearing prices based upon incremental resources used to serve load. Demand and energy forecasts used by PROSYM are developed and provided by the vendor. Annual updates of these forecasts are provided by the vendor based on data obtained from EIA filings and independent analysis by the vendor. For purposes of this revenue requirement determination, the demand and energy forecasts used were those that have been described earlier.

In its hourly dispatch, PROSYM reflects the primary engineering characteristics and physical constraints encountered in operating generation and transmission resources, on both a system-wide and individual unit basis. Within PROSYM, thermal generating resources are characterized according to a range of capacity output levels. Generation costs are calculated based upon heat rate, fuel cost, and other operating costs, expressed as a function of capacity output. Physical operating limits related to expected maintenance and forced outage, start-up, unit ramping, minimum up and down time, and other related characteristics are reflected in the PROSYM simulation.

Hydroelectric resources are also characterized in PROSYM according to expected output levels, including monthly forecasts of expected energy production. PROSYM schedules run-of-river hydroelectric production based upon the minimum capacity rating of the unit. The dispatch of remaining hydroelectric energy is optimized on a weekly basis by scheduling hydro production in peak demand hours when it provides the most value to the electrical system.

Within the PROSYM framework, regional market-clearing prices are established based upon the incremental bid price of the last generating station needed to serve demand. For most of the existing supply, bid prices are composed primarily of incremental production costs. Hourly energy revenues for each generating unit are established as the product of market-clearing prices and the unit's energy production during the relevant hour. The PROSYM framework mirrors a "single-price" auction, so that each generator located within the same market area receives an identical price for its energy output, regardless of its actual bid price or production cost.

While the only "single-price" market auction that still exists in California is the CAISO imbalance energy market, this pricing mechanism is modeled as a proxy for the average price of the residual net short. In the long term, under a balanced supply and demand market, the average residual net short price should approximate the market-clearing price in an "as-bid" environment. In the near-term, the use of a single-price mechanism for the residual net short produces a reasonable assessment of market prices.

Based upon the bid price of the marginal generating station in a given hour, the market-clearing price is calculated using the following general approach (stated in dollars per MWh):

Market-Clearing Price = Incremental Production Cost + Start Cost + No-Load Cost + Price Markup

Where:

- Incremental Production Cost is calculated as each station's fuel price multiplied by the incremental heat rate, plus variable operations and maintenance cost;

- Start Cost incorporates fuel costs and other operating costs encountered in starting the generating unit, beyond those reflected in the heat rate and variable operating cost assumptions;

- No-Load Cost reflects the difference between average and incremental fuel costs for generating stations that are dispatched at less than full output; and,

- The Price Markup factor recognizes that market forces may drive bid prices above variable production costs. The Department uses this factor to reflect observed market behavior where wholesale prices often rise above the underlying cost of production, particularly during times when supply/demand margins are tight. Such behavior is common in power markets.

Price Markups are assigned to individual generators depending upon the underlying fuel efficiency, production cost, and technology type. The specific Price Markups are designed so that bid prices rise above the cost of production as less efficient resources are called upon for power production and as the intersection of supply and demand occurs at higher points on the supply curve. The level of Price Markups is determined through an iterative approach with the goal of benchmarking against recent actual wholesale prices, and against observable prices in the forward market.

Three specific bidding strategies were assigned:

1) Incremental Cost Bidding: Units assigned incremental bidding strategies incorporate only variable operating costs into their bid prices. This bidding strategy reflects a highly competitive market structure. All base load resources and generators with relatively low production costs are assigned this bidding strategy, which reflects the bulk of available supply resources.

2) Price Markup Bidding: Units assigned Price Markup bidding strategies submit bids close to variable operating costs during all off-peak hours. During on-peak periods, when electricity demand is higher, these stations seek to markup price in proportion to the level of electricity demand. The price markups also vary by season, and are at higher levels during the summer and winter periods when supply/demand balances are the tightest. Intermediate-type generating resources such as older steam turbine units having relatively high production costs are assigned this bid strategy.

3) Peak Period Bidding: Units assigned Peak Period bidding strategies also submit close to variable operating costs during off-peak hours. Price markups are assigned to these resources during on-peak hours and seasonally. The markups for resources in this category tend to be higher than those applied under the Price Markup strategy. Resources that are assigned Peak Period bidding strategies tend to have the highest production costs, such as simple-cycle gas turbine generators and internal combustion oil-fired plants. Such resources are called upon to produce power only a small portion of the time each year.

The table below provides an overview of bid strategy assignment used in the analysis underlying this determination. As shown, bid prices are set for a majority of supply resources based on incremental production costs.

CALIFORNIA AND WECC BID STRATEGY ASSESSMENT
(PERCENT OF SUPPLY)

	Incremental	Price Markup	Peak Period Bidding	Total
California	68%	28%	4%	100%
Non-California	80%	14%	6%	100%
Total WECC	75%	20%	5%	100%

FERC Price Mitigation

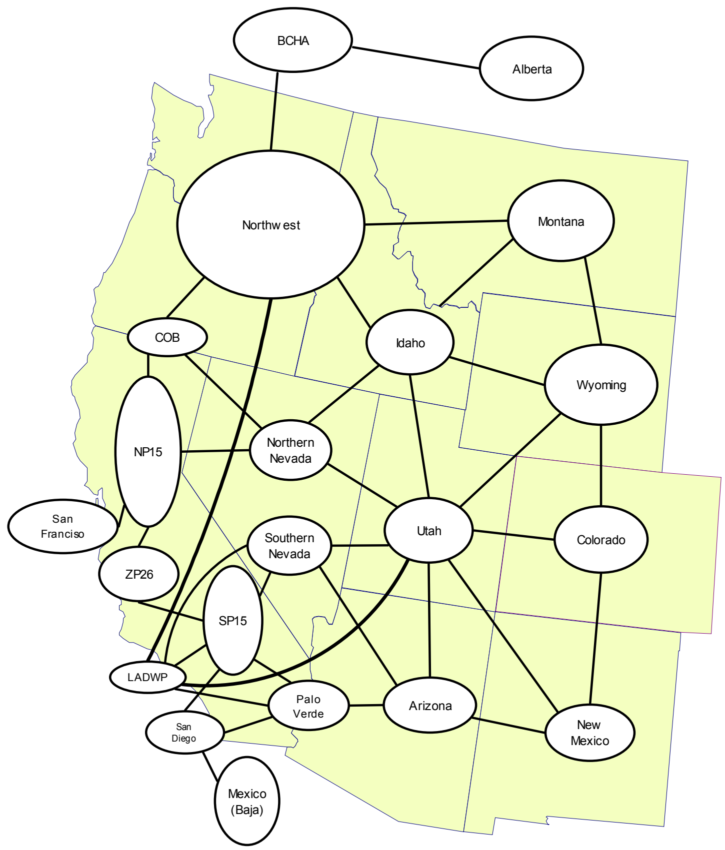
On July 17, 2002, FERC issued an order related to CAISO market design initiatives that established a hard price cap of $250 per MWh, effective October 1, 2002. For purposes of this Determination, the price cap is assumed to remain in effect throughout the 2004 Revenue Requirement Period.

WECC Regional Market Definitions

WECC electricity markets sometimes experience binding transmission constraints. Binding transmission constraints occur at times when transmission capacity on a specific linear path is fully utilized and no additional energy can be transported via that line or path. During such times, low-cost generators are forced to reduce output in favor of higher-cost units located within the constrained region.

To reflect transmission constraints encountered in WECC markets, the Department simulated 21 separate market regions, with transfer limitations between each region reflecting expected transmission system configurations. In selecting market regions, the Department examined WECC transmission system operations and also analyzed a number of transmission publications and studies prepared by the WECC.

Separate market-clearing prices were established within each regional market as shown in the figure. In establishing the market-clearing price for each region, the PROSYM simulation took into account economic import and export possibilities and set the market-clearing price as the bid price of the marginal generator needed to serve a final increment of demand within the region.



Simulation of New Resource Additions

To meet increases in peak demand, new resource additions must be included in the simulation. A review of potential and planned new resource additions throughout the WECC reveals that they will be built and owned primarily by independent power producers. Generally, the technology, fuel type, size, and location of these new plants will depend primarily upon wholesale power market prices. Prices available to an independent power producer must be sufficient to allow it to earn a return on equity that is consistent with similar risk capital investments.

To forecast the amount of capacity added in each region of the WECC, known potential new generating resources were reviewed to identify those currently under site certification or construction. These plants have a high probability of completion and were added to the simulation resource base in their expected year of completion. Capacity costs of the particular resource to be added are estimated based on publicly available cost information for the specific type of plant, and on certain financing term, interest rate, and return on equity assumptions.

The table below summarizes these assumptions for combustion turbine and combined cycle combustion turbine plants, which are expected to represent the major portion of all new generating resource additions in the WECC during the 2004 Revenue Requirement Period.

GENERIC RESOURCE ASSUMPTIONS

Unit Characteristic	Combustion Turbine	Combined Cycle
Heat Rate (Btu/kWh)	11,000	7,100
Fixed O&M ($/kW-year)	3.15	10.50
Variable O&M ($/MWh)	4.20	2.10
Forced Outage Rate (%)	0.00	2.00
Maintenance Outage Rate (%)	4.00	4.00
Financing Term (Years)	15	15
Interest Rate (%)	8.00	8.00
Return on Equity (%)[1]	18.00	18.00

Source: NCI. Cost figures represent 2002 dollars.
[1] After taxes.

To the extent the production simulation model determines that additional generating capacity, beyond that designated as planning capacity, is needed to meet the needs of the region, "generic" new generating units are assumed to be added to the resource mix.

Long-Term Power Contracts

The Department's contract resources were explicitly modeled in the simulation, accounting for their respective capacities, delivery points, minimum takes and other features. These contract resources are assumed to be called upon as a resource for meeting Customer needs and are expected to be dispatched in an economically efficient manner (from the Customers' perspective) as part of a complete resource mix that includes the utility retained generation, the Department's contracts, and residual net short purchases. The Department's Long-Term Power Contracts are available for viewing at the Department's web site: http://www.cers.water.ca.gov.

Other Assumptions

A broad array of other inputs and assumptions were made in performing the WECC market simulation. These inputs and assumptions address resource availability, resource retirements, fuel prices, operation and maintenance costs, outage factors, transmission factors, and market conditions, among other factors, which are summarized in the table below.

Category	Assumption
Study Period	January 2004 through December 2004.
Load Forecast	From the EIA-411 filings of the WECC, except for IOU forecasts, which were developed as described elsewhere in this Determination.
Load Profiles	SCE and SDG&E load profiles were provided by the IOUs. The PG&E load shape was based on the composite hourly load profile for the 1993-1998 period contained in PROSYM, The PG&E load profiles were derived from hourly Edison Electric Institute load data files from the FERC web site.
Existing Resources	From the WECC EIA-411 filings.
Pacific Northwest Hydro	BPA 2000 Pacific Northwest Loads and Resources Study used to calculate monthly capacity and energy values for each hydroelectric station in the region, choosing median conditions from a recorded database of 50 years
California Hydro	WECC Coordinated Bulk Power Supply report for summer and winter capacity ratings for existing hydro resources.
Resource Retirements	No nuclear retirements at license expiration
Gas Prices	See "Natural Gas Price-Related Assumptions"
O&M Costs	Historical, power plant-specific, non-fuel operation and maintenance ("O&M") costs reported by utilities to FERC, averaged and normalized to develop average starting O&M costs. Amounts allocated between fixed and variable O&M costs. Both fixed and variable O&M costs are assumed to escalate with inflation.
Thermal Resource Models	• Multi-segment incremental heat rate curves. • Fixed and variable O&M costs. • Scheduled outages based on annual maintenance cycles. • Random forced outages based on unit-forced outage rates.
Contracts	• Known firm purchase/sales reported in the WECC Form OE-411 filing. • Transactions are reflected in the load requirements of the buying and selling utilities, in transactions between regions, and by adjusting the transmission capacity. • Transmission capacity between zones required for these transactions is assumed to have priority. Any remaining transmission capacity is used to facilitate additional power transactions between regions, based on economic dispatch and delivery over the remaining transmission capacity.
Thermal Resource Commitment and Dispatch	Unit commitment order determined by marginal operating cost (fuel and variable O&M costs). Commitment determined to satisfy load plus spinning reserve.
Transmission Model	Transmission system and constraints represented using transport model across regions.
Market Structure	Assumed open market across all the regions (region-wide dispatch). Energy interchange between regions occurs when spot price differentials exceed transmission tariff costs.

H. Reference Index of Materials Upon Which The Department Relied to Make Determinations

Quasi-Legislative Record of Revenue Requirement Reasonableness Determination

Determination of Revenue Requirements Dated November 5, 2001.

Determination of Revenue Requirements Dated August 16, 2002, Including Specifically Appendix 3, entitled Reference Index of Materials Upon Which the Department Relied to Make Determinations

Supplemental Determination of Revenue Requirements (for 2003), dated July 1, 2003, including specifically Section “G” entitled “Reference Index of Materials Upon Which the Department Relied to Make Determinations”

DWR work-paper entitled Section G 2004 Reconciliation of Revenue Requirements

Commission Decision 02-12-045 “Opinion Adopting Interim Allocation Of The 2003 Revenue Requirement Of The California Department Of Water Resources”, dated December 17, 2002

Commission Decision 02-12-052 (Order Correcting Error) issued on December 17, 2002

Commission Decision 03-02-031, dated February 13, 2003

Commission Decision 02-09-053 dated September 19, 2002

PROSYM, a price forecasting and market simulation tool

PG&E, SCE, SDG&E and the California Large Energy Consumers Association (CLECA) submitted assumptions for the Department’s consideration in a supplemental determination

U.S. Energy Information Administration’s report of 2002 production (gas)

CPUC Decision 02-12-069, dated December 19, 2002; regarding Operating Orders between DWR and IOUs

March 6, 2003 memorandum to Honorable Geoffrey F. Brown, Commissioner and Honorable Loretta M. Lynch, Commissioner from Peter S. Garris of the Department, on the subject of: WAPA--Under-remittance associated with energy deliveries to retail customers in the service territory of Pacific Gas and Electric Company

CPUC Decision 02-11-022, dated November 13, 2002 enacting a cost responsibility surcharge for direct access customers

DWR’s California Water Supply Outlook runoff forecast, dated February 1, 2003

National Weather Services Northwest River Forecast Center runoff forecast for The Dalles, March 3, 2003 Early Bird Forecast

Testimony of Mr. Frank Perdue of Navigant Consulting, on behalf of DWR, during the CPUC hearing process on the August 16 Revenue Requirement, October 3 and 4, 2002

Transcript of hearings conducted by ALJ Allen on October 2, 3, and 4, 2002

State of California Department of Water Resources Power Supply Revenue Bonds and related swaps (documentation)

Volumes 1 – 7, Dated October 30, 2002
$1,000,000,000 Series 2002B
$2,750,000,000 Series 2002C
$ 500,000 000 Series 2002D

Volumes 1 – 4, Dated November 14, 2002
$6,313,500,000 Series 2002A
$ 700,000,000 Series 2002E

CPUC Decision 02-08-071, dated August 22, 2003

CPUC Decision 02-09-045, dated September 19, 2002

CPUC Decision 02-10-035, dated October 17, 2002

CPUC Decision 02-10-062, dated October 24, 2002

CPUC Decision 02-10-063, dated October 24, 2002

CPUC Decision 02-10-067, dated October 24, 2002

CPUC Decision 02-11-026, dated November 7, 2002

Peter S. Garris Memo to Paul Clanon, CPUC, dated November 8, 2002; Submittal of "more precise" bond revenue requirement after bond placement

CPUC Decision 02-11-074, dated November 21, 2002

CPUC Decision 02-12-027, dated December 5, 2002

ALJ Allen and ALJ Pulsifer Joint Ruling Regarding the process to implement direct access CRS, dated December 10, 2002

CPUC Decision 02-12-074, dated December 19, 2002

CPUC Decision 02-12-071, dated December 19, 2002

CPUC Decision 02-12-072, dated December 19, 2002

CPUC Decision 02-12-082, dated December 30, 2002

CPUC Decision 03-02-032, dated February 13, 2003

CPUC Decision 03-20-036, dated February 13, 2003

CPUC Decision 03-02-072, dated March 4, 2003

CPUC Decision 03-05-034, dated May 8, 2003

CPUC Decision 03-05-036, dated May 8, 2003

Peter S. Garris letter to Paul Clanon, CPUC, dated May 14, 2003; regarding remittance of Direct Access CRS

PG&E 1st Quarter Report to the Securities and Exchange Commission (10Q)

Pacific Gas and Electric Company's Comments on the California Department of Water Resources' Proposed Supplemental Determination of Revenue Requirements for the Period January 1, 2003 Through December 31, 2003, dated June 23, 2003

Southern California Edison Company's Comments on the California Department of Water Resources' Proposed Supplemental Determination of Revenue Requirements for the Period January 1, 2003 Through December 31, 2003, dated June 23, 2003

San Diego Gas and Electric Company's Comments on the California Department of Water Resources' Proposed Supplemental Determination of 2003 Revenue Requirement, dated June 23, 2003